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Designing a Remedial Acid Treatment for Gulf of Mexico Deepwater Turbidite Sands Containing Zeolite Cement

B.A. Rogers, SPE, M.K. Burk and S.A. Stonecipher, Marathon Oil Company

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Abstract

Ewing Bank 873 Field, developed from mid 1994 through 1995, produces from deepwater turbidite sands at an average depth of 11,000' TVD. Water depth at the platform is 775'. In early 1996, pressure transient analysis of bottom hole pressure build-up surveys indicated increasing skins. Before pumping any type of remedial stimulation treatment, it was decided to test the recommended acid formulation in the lab. Acid corefloods were performed on composite samples from whole core using a typical 10% HCl/1.5% HF formulation. This acid formulation proved to be damaging as lab results indicated losses in permeability of up to 74%. A series of core floods were then performed on composite core samples to test the effects of various mud acid formulations, pre-flushes, post-flushes and acid additives. X-ray diffraction (XRD) and scanning electron microscope (SEM) analysis were also performed to help in determining the cause and mechanism of the damage. Results indicated that the loss in permeability was associated with acid additives which were causing fines migration and with silica gels precipitated as a result of the aggressive reaction of HCl with zeolite (clinoptilolite) within the formation. An optimum treatment formulation was identified, consisting of 10% Citric/1.5% HF acid, with no additives except corrosion inhibitor. This treatment was successfully applied in the field to five producing wells. Aggregate rate increased from 7400 BOPD to 16,000 BOPD and productivity index (PI) increased from 4.78 to 12.73 BOPD/psi of drawdown.

Introduction

Ewing Bank 873 is a flextrend Gulf of Mexico field located approximately 200 miles south of New Orleans, Louisiana in 775 ft of water that was discovered in 1991. The discovery well was sidetracked and three delineation wells were drilled over the

following 12 months to define the productive limits of Pliocene age Bulminella (Bul-1) reservoir. The reservoir series of seven stacked and overlapping deep water turbidite s deposited in a salt-withdrawal mini-basin as shown in Figu. The trap is formed by faults on the eastern and western mar of the field and by an updip pinchout of the turbidite sand: shown in Figure 2. Porosity in these unconsolidated reser sands ranges from 25 to 30%, with permeability ranging from to 1600 md. Oil gravities are between 15 and 26° API. The sands extend over a 3000 ft oil column from 9500 ft TVI 12,500 ft TVD.

Whole cores were obtained in Wells A-2 and A-4. Petrographic analysis had been done on the cores by two independent labora ries prior to field development. Both analyses indicated the trace to 5% zeolite; a hydrated aluminum silicate cement form from chemically altered volcanic rock fragments was prese. Zeolite has a platelike crystalline structure, ranging from 10 microns in size. Based on these analyses, a typical 15% HCl/ HF mud acid would be compatible with the mineralogy.

The production platform was installed in the summer of 19 with facilities designed to handle 35,000 BOPD. The discove well and the three delineation wells were tied back to the platform and completed immediately after platform installation. C production commenced in August, 1994. After batch drilling at completing three more wells, platform processing limits 48,000 BOPD were reached in April, 1995. A total of te producers and three seawater injectors were completed in the initial field development of the Bul-1 reservoir. Drilling and completion practices utilized during the development were designed to optimize well deliverabilities'. All productio intervals were drilled with synthetic fluid to minimize formation damage and maximize penetration rates. All completions incorp rated frac-pack or mini-frac technology designed to overcome an near wellbore skin damage and prevent sand migration into the wellbore during production. As shown in Figure 3, oil production rates were maintained at platform processing limits for over a year. The field's producing GOR has remained relatively constant since initial production at approximately 750 scf/STB.

First water production occurred in mid 1995 and has steadily increased. Water injection was implemented downdip of the oil-water contact to provide pressure maintenance. Rapid pressure depletion occurred through the middle of 1995 when production withdrawals were balanced by aquifer influx and water injection.

Approximately 1,200 psi total depletion has occurred since first oil production began.

In order to evaluate completion efficiencies and for benchmarking purposes, bottom hole pressure build-up or fall-off surveys were performed within the first few months following each well's completion. Subsequent bottom hole pressure testing has been performed to monitor changes in completion efficiency and reservoir pressure depletion. In early January, 1996, bottom hole pressure surveys were performed on every producing well. Reservoir pressure had stabilized as can be seen in Figure 4. Permeability had declined to approximately 20-30% of original values due to compaction of the unconsolidated reservoir rock as a result of pressure depletion². The loss of permeability was expected and had been predicted by laboratory experiments.

What was not expected was the increase in skin in the majority of the producing wells as shown in Figure 5. This was a major concern since several of the major producers had now reached drawdown limitations that we had imposed in order to preserve completion integrity. If completion skins continued to increase, it would mean that we would have to relax our drawdown limitations or go on production decline for the first time in the life of the field. As it turned out, both of the above happened. Drawdown limitations were relaxed from 1000 psi to our current limit of 1500 psi. Rapidly increasing skins soon took their toll, however, and production was allowed to decline as we adhered to our new maximum drawdown limits. Since the drilling rig had already been demobilized, the only quick and cost effective way to arrest the production decline was to design and implement an acid stimulation treatment for the wells which would significantly reduce skin.

Laboratory Design

Before pumping any type of mud acid stimulation, it was decided to test the recommended acid formulation in the lab. Since the Bul-1 reservoir was so unconsolidated, conventional core plugs could not be taken from the whole cores we had from Wells A-2 and A-4. Instead, large composite samples were created for both wells by combining loose sand from several quality sand intervals in each whole core. A sand pack was then prepared in a 1" rubber Hassler core holder sleeve by first installing a fine wire mesh screen, followed in turn by 2" of 20/40 gravel pack sand, 6" of loose composite core sample, 2" of 20/40 gravel pack sand and capped with a 1/4" 40/60 mesh resin coated sand disk. The sand was firmly compacted as it was being loaded into the rubber core holder. The purpose of this core plug design was to attempt to simulate the actual gravel packs in place. The 2" of gravel pack sand at the end of the core plug was included only to hold back the reservoir sand. A picture of one of the core plugs is shown in Figure 6. The core plug was then inserted into the Hassler core holder, 900 psi of confining pressure placed on the core sleeve and the apparatus placed in an oven set at 160° F. The pore volume in the formation sand portion of these sand packs was approximately 23 ml.

A baseline permeability was obtained by saturating a Well A-2 core with a simulated formation brine and then displacing the brine with EW-873 crude oil. Differential pressure was recorded

as 300 ml of the crude oil was pumped through the core 0.75 - 1.0 ml/min. A typical half strength mud acid treatment was prepared, which consisted of 300 ml xylene with 1% solvent preflush, 300 ml of 10% HCl/10% Acetic/5% solvent/0.5% surfactant/2% chelating agent/0.5% in corrosion inhibitor preflush and 300 ml of 10% HCl/0.5% surfactant/2% chelating agent/0.5% inorganic co-inhibitor. This treatment was pumped at 10 ml/min. To test the change in permeability as a result of this treatment, 300 ml crude oil was again pumped at 0.75 - 1.0 ml/min. The result, shown in Table 1, was a 54% loss in permeability. This treatment was repeated on a Well A-4 core with similar results, a 74% loss in permeability. The same treatment was repeated on another Well A-2 core, but the mud acid was followed by 300 ml of fluoboric acid, again with the same results, a 62% loss in permeability.

At this point, it appeared that designing a successful formulation for this reservoir rock might not be a simple procedure. The first task was to identify the reason for the high initial permeability. This would require several more acid corefloods and a deeper investigation into the rock itself utilizing X-ray diffraction and a scanning electron microscope (SEM). Due to the potentially large number of corefloods we would have to rule out acid leaching of the core. We decided to concentrate only on Well A-2 core, since Well A-2 exhibited the greatest increase in skin. In order to enable us to examine the corefloods in the vacuum of the SEM, the crude oil phases had to be removed from the procedure. They were replaced by 5% ammonium chloride and a fresh water preflush added at the end of the flood to remove salt crystals. The change in permeability was then measured by the change in differential pressure across the core required to pump the ammonium chloride stages through the core at 10 ml/min before and after the acid treatment was pumped. The volume of various stages were varied to study the effect on permeability. All of the remaining corefloods were performed in this manner.

As a first step, in-house X-ray diffraction analyses were performed on Well A-2 and A-4 core to verify the mineralogy. These analyses indicated that the zeolite content in Well A-2 was actually in the 15-20% range, whereas Well A-4 contained only 0-2% zeolite. As shown in Figure 5, these values correlate with the observed increase in skins i.e., there was a dramatic increase in skin in Well A-2 associated with the high zeolite content and a very little increase in skin in Well A-4 where the zeolite content was low. Figure 7 shows an SEM photograph of the zeolite platelets in Well A-2.

The second set of tests were designed to examine the effects of compaction. Core samples from Well A-2 and A-4 were placed in a triaxial core holder and loaded to simulate overburden forces on the reservoir rock resulting from pressure depletion. The cores were then examined with the SEM after unloading. In Well A-2 it was found that the soft zeolite cement had severely deformed and actually flowed into the pore throats. In Well A-4, on the other hand, where there was no ductile zeolite to absorb stress, silicate fines consisting of crushed feldspars and broken edges of quartz grains were generated. These observations explained why the near wellbore skins increased so rapidly in wells that had high

zeolite concentrations. As reservoir pressure depleted and as near wellbore drawdown increased, compaction effects caused the zeolite particles to extrude into the pore throats and reduce permeability significantly in the near wellbore region.

The fourth coreflood that we ran was very enlightening. We observed that there was a substantial loss in permeability while we were pumping 5% ammonium chloride, with 1% mutual solvent and 0.5% clay stabilizer into the core. Several acid stages were pumped through this core, each followed by ammonium chloride. On the ammonium chloride stage after a 550 ml 10% HCl/1.5% HF stage, we decided to omit the additives. The result was no loss in permeability while pumping the ammonium chloride. We added the mutual solvent and clay stabilizer back into the ammonium chloride and again experienced the same trend in permeability loss. A 764 ml stage of fluoboric acid was then pumped through the core, followed by ammonium chloride with no additives. This coreflood resulted in the largest gain in permeability, +53%, that we experienced in any of the corefloods, however, several large acid stages were required. SEM analysis of this coreflood, however, were not too encouraging. The injection end of the core exhibited common remnants of incompletely dissolved zeolites (see Figure 8), which partially filled some of the pores. In contrast, pores in the output end of the core were commonly filled with large clots of authigenic silica gel. We were concerned that the silica gel we had generated would either flow back with time in the production mode or undergo the same sort of compactional deformation as the zeolite and result in another loss in near wellbore permeability. We and others had experienced these type of results in the past in other fields with mud acid, where the gain in productivity was relatively short lived³. The objective of this study was to find a treatment that would not only improve productivity, but also maintain high productivity over an extended period of time.

Because the key to maintaining high productivity after treatment appeared to be tied to keeping dissolution products in solution, it was decided to look at organic acids, which have the ability to enhance the solubility of aluminosilicates by chelating aluminum⁴. Aluminum hydroxide precipitates appeared to act as templates which facilitate the formation of silica gels. This search lead us to try several organic mud acid mixtures. The first formulation chosen consisted of an 8% Oxalic/1.5% HF acid mixture because oxalic acid has been shown to be one of the most active with respect to aluminosilicate dissolution⁴. The first flood with this formulation exhibited a relatively small loss in permeability, good dissolution of fines and generated little to no silica gel. A higher concentration, 8% Oxalic/3.0% HF mixture, resulted in a higher loss in permeability, extensive fines dissolution and silica gels were once again generated. The 8% Oxalic/1.5% HF mixture at first appeared to be a viable candidate, but it was found to have the potential to precipitate calcium and sodium oxalates when compatibility tests were run with formation brine. In addition, due to the lower ionic strength of the organic mud acid mixtures, compared to the inorganic mud acid, it was decided that we would need to add 5% ammonium chloride to the organic mud acid to insure we would not induce clay swelling. Difficulty was also experienced in trying to dissolve an

8% solution of oxalic acid in the 5% ammonium mixture. For these reasons, Oxalic/HF formulations were unacceptable.

Citric acid, commonly used as an iron sequestering acid stimulations, has also been reported to enhance solubility aluminum and silicon^{5,6}. When 8-10% Citric/1.5% HF solutions were pumped through the cores, the results proved to most encouraging of any of the corefloods. These mixtures yielded relatively low losses in permeability, from 8-21% dissolution of fines and no silica gel (see Figure 9). Compatibility problems existed with the formation brine as citric acid could be mixed at high concentrations. The additive put into this mixture was 0.5% corrosion inhibitor. It also had determined that there was no benefit from any type preflush. Based on these laboratory results, even with a net increase in permeability, we were ready to initiate a field test with Citric/HF mixture. The chemistry of the mixture appeared right. It dissolved what we wanted it to and did not leave behind any unwanted precipitates. If we could have simulated the wellbore damage in the coreflood, we would have expected improvements in permeability. Since we were starting with an undamaged sand pack, just minimizing damage caused by treatment was acceptable. Our best acid candidate was Well

Field Implementation

The first well to be treated with the Citric/HF acid formula was Well A-2. This well had a 121 ft frac-packed interval. The well had produced 4500 BOPD initially with 650 psi drawdown and a skin of +10. After almost 2 years and over 2 million barrels of oil production, the production rate had fallen to 1377 BOPD with 1600 psi of drawdown and a skin of +93.

The acid treatment designed for Well A-2 consisted of 12,000 gallons of 5% ammonium chloride pre-flush, 15,000 gallons of 10% Citric/1.5% HF/5% ammonium chloride/0.3% organic acid corrosion inhibitor and 5000 gallons of 5% ammonium chloride. The treatment was designed to be bullheaded down the production tubing using rate and pressure for acid diversion⁷. A maximum BPM rate, not to exceed 4000 psi surface treating pressure was decided upon. The 4000 psi surface limitation would avoid reaching fracture pressure at the sandface, based on bottomhole pressure data obtained during the initial frac pack. The 50 gallons of post-flush would be just enough to displace the acid treatment to the gravel pack screen. A large overflush was not designed. In the laboratory, the HF acid was consistently spent within the first two inches of reservoir sand. It did not seem advantageous to push this spent acid back further into the formation, raising the pH in the near wellbore area by doing so and then put the well on production. The spent acid flowing back through the near wellbore area would have more tendency to leach out precipitates in a higher pH environment created by a large post-flush, than in a low pH environment, as a result of no post-flush actually reaching the formation.

The size of the treatment, along with the required pump rates made the use of a frac boat necessary. The Citric/HF was batch mixed using a pre-mixed 5% ammonium chloride solution, to which dry citric acid was added, then concentrated liquid HF and

a liquid corrosion inhibitor. The treatment was bullheaded down the production tubing. The injection rate was 2.5 BPM at 3450 psi when the acid reached the perforations. At the end of the treatment, the injection rate was 3 BPM at 1900 psi. The well was put back on production immediately and flowback samples were taken every hour. After the well had cleaned up, the production rate was increased to 3400 BOPD. A follow up bottom hole pressure build-up survey confirmed that the drawdown had dropped to 1250 psi at this rate and skin had decreased to +14. After another year and almost another 1 million barrels of oil production, Well A-2 is still producing 3300 BOPD, with a skin of +12.

Shortly after the successful treatment was pumped on Well A-2, similar treatments were designed for two water injection completions. The biggest difference in the treatment design was in the way the Citric/HF was mixed. In these treatments, the acid was batch mixed using a pre-mixed 5% ammonium chloride solution, to which concentrated liquid citric acid was added, then dry ammonium bifluoride and a liquid corrosion inhibitor. These treatments increased injectivity from 1500 BWPD at 3500 psi injection pressure (IP) to 7800 BWPD at 3000 psi IP in Well A-14 and from 3500 BWPD at 3500 psi IP to 6400 BWPD at 2950 psi IP in Well A-12.

Turning our efforts now in the direction of field Citric/HF formulation, several formulations were prepared in the lab using a concentrated liquid HF and solid ammonium bifluoride. As can be seen in Table 2, the acid prepared with the liquid HF was a stronger acid, with a lower pH. If one were using an HCl/HF mixture, the problem with using solid ammonium bifluoride or aqueous ammonium fluoride is not very significant. To make a 1.5% HF solution using ammonium fluoride uses up about 2.7% HCl. Using ammonium bifluoride uses just half that amount, 1.4% HCl. Formulating a Citric/HF mixture with ammonium bifluoride or ammonium fluoride makes the problem more complicated and severe. Citric acid contains three distinct acid hydrogens (-COOH), each one with a different acid strength. To make a 1.5% HF solution using ammonium fluoride, it would require a 14.4% solution of citric acid to have enough of the first and strongest acid groups available for consumption. Again, using ammonium bifluoride would require just half this amount, 7.2%. The first and strongest hydrogen of all the citric acid molecules are used up before the second hydrogen is consumed, thus resulting in a weaker acid system. For these reasons, it was decided that all future Citric/HF treatments would be prepared using concentrated liquid HF.

Strict quality control guidelines were also implemented. Laboratory analysis of any concentrated acids had to be verified by supervisory personnel on the boat. Every batch of acid mixed on the boat would have to be checked for density and pH as per the results in Table 2 before being pumped downhole. Live acid samples of every batch mixed are also to be taken for laboratory analysis.

The desire to pump these treatments at even higher rates led to another evolution of field Citric/HF formulation. To accomplish these desires, concentrated liquid Citric/HF was pre-mixed at the acid plant. This concentrated mixture is then diluted on the fly in

the batch mixing process and has allowed us to achieve in rates of up to 14 BPM. Since these changes have been implemented, several successful Citric/HF treatments have been pumped, none of these treatments showing any negative effect. A summary of the treatments is shown in Table 3. As shown, oil production was initially increased by over 8500 BPD as a result of these treatments. Oil production is still up by 6000 BPD due to these stimulations, 6 to 16 months after the treatments were performed. Water injection was increased by 9000 BPD initially, but these treatments had to be repeated.

As a follow up to our Citric/HF acid stimulation treatments, several wireline production logs were run to determine the effectiveness of diversion we were achieving. These spinner surveys indicated that diversion was achieved over the entire interval in almost all of the treatments analyzed, largely as a result of the very high injection rate used during the treatment.

Conclusions

1. Zeolite rich formations can lead to increasing skins as a result of reservoir compaction and fines migration, even in packed completions.
2. Accurate quantitative knowledge of the mineralogy of reservoir rock to be acidized is critical.
3. Testing an acid system in the laboratory on actual reservoir rock is essential with complex mineralogy or little completion experience.
4. SEM analysis of a coreflooded sandpack is an excellent method to help rate the effectiveness of an acid treatment and to provide insight to the cause of increasing near wellbore skins.
5. Chemical additives to acid treatments should only be included if they prove to be beneficial. Some additives can contribute to formation damage and fines migration.
6. The 10% Citric/1.5% HF acid formulation is effective in dissolving chemically reactive formation fines such as zeolites without the creation of significant quantities of silica gel, thus preventing dissolution products from reprecipitating.
7. 10% Citric/1.5% HF acid treatments provide results with greater longevity due to the lack of silica gel residue left in the formation.
8. Using rate and pressure for acid diversion can be an effective way to treat long intervals, eliminating the need to use potentially damaging foam or oil soluble resin diverting agents.
9. Citric/HF acid mixtures should be mixed using concentrated liquid HF and not ammonium fluoride or ammonium bifluoride.
10. Strict quality control guidelines need to be included in all treating procedures and be closely adhered to.

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TABLE 1 - CORE FLOOD RESULTS

CORE	XYLENE PREFLUSH	MUTUAL SOLVENT PREFLUSH	ACID PREFLUSH	MUD ACID	FLUO- BORIC ACID	NH4CL INJ. PSI BEFORE	NH4CL INJ. PSI AFTER	PERM CHANGE %	SEM POST ANALYSIS	
									SEM	POST ANALYSIS
A-2	YES	YES	10%HCl/10%HAC	10%HCl/1.5%HF	NONE	220	475	-54	Note: inj psi of crude oil, NH4Cl postflush had mutual No SEM	
A-2	YES	YES	10%HCl/10%HAC	10%HCl/1.5%HF	NONE	110	420	-74	Note: inj psi of crude oil, NH4Cl postflush had mutual No SEM	
A-2	YES	YES	10%HCl/10%HAC	10%HCl/1.5%HF	YES	200	525	-62	Note: inj psi of crude oil, NH4Cl postflush had mutual No SEM	
A-2	NO	YES	3%HCl/3%HAC 10%HCl/10%HAC	3%HCl/0.5%HF 10%HCl/1.5%HF	YES	55	36	53	Inj end has melted zeolites, some pore filling, prod end has much silica gel	
A-2	NO	NO	10%HCl/10%HAC	10%HCl/1.5%HF	YES no add	38	52	-27	Inj end has removed and fused zeolites, prod end has silica gel, ilite in middle of core	
A-2	YES	NO	3%HCl/3%HAC	NONE	YES no add	12	37	-68	Inj end has some dissolution, prod end is untouched, possible migration of fines generated by dissolution	
A-2	YES	YES	10%HCl/10%HAC	10%HCl/1.5%HF	YES	25	25	0	Inj end has dissolution and silica gel, prod end also show dissolution and silica gel	
A-2	YES	YES	10%HCl/10%HAC no add	10%HCl/1.5%HF no add	YES no add	37	27	37	Inj and prod ends show much dissolution and silica gel	
A-2	YES	NO	NONE	8%HOX/1.5%HF	NO no add	30	40	-25	Inj end has dissolution, prod end untouched, no silica gel	
A-2	YES	YES	NONE	8%HOX/1.5%HF	NO	30	48	-38	Inj end has dissolution and much silica gel	
A-2	NO	NO	NONE	8%HOX/1.5%HF	NO	25	34	-26	Inj end has dissolution, prod end has trace to no silica gel	
A-2	NO	NO	NONE	10%HFM/1.5%HF	NO	17	27	-37		
A-2	NO	NO	NONE	8%HOX/3.0%HF	NO	25	45	-44	Inj end has extensive dissolution, prod end has silica gel	
A-2	NO	NO	NONE	10%HFM/1.5%HF	NO	15	22	-32	Inj end has mod/exten dissolution, prod end has minor silica gel	
A-2	NO	NO	NONE	10%HCL/1.5%HF	NO	17	24	-29	Inj end has extensive dissolution & silica gel, prod end also shows dissolution and silica gel	
A-2	NO	NO	NONE	NONE	YES	17	22	-23	Inj end has mod/good dissolution, prod end has minor silica gel and some dissolution	
A-2	NO	NO	8% HOX	NONE	YES	20	33	-39	Inj end has extensive dissolution and filling of pore spaces, prod end shows minor dissolution	
A-2	NO	NO	NONE	8% Citric/1.5% HF	NO	30	32.5	-8	Inj end has extensive dissolution, no silica gel, prod end has no dissolution	
A-2	NO	NO	NONE	10% Citric/1.5% HF w/5% NH4CL	NO	21	26.5	-21	Inj end has extensive dissolution, no silica gel, prod end has no dissolution	

TABLE 2 - PROPERTIES OF ACID MIXTURES

Acid Mixture	Density (g/ml)	pH Measurement Test Strip	Glass Probe
50 wt% Citric acid (anhydrous)	1.2393	0.6	0.72
50 wt% Citric acid (54.7% monohydrate)	1.2423	0.6	0.76
10% Citric, 5% NH4Cl, 0.5% corr. inhib.	1.0578	1.3 - 1.5	1.65
10% Citric, 1.5% HF, 5% NH4Cl, 0.5% corr. inhib.	1.0622	0.6	
10% Citric, 1.5% HF, 5% NH4Cl, 0.2% corr. inhib.	1.0624	0.6	
10% Citric, 1.5% HF via 2.14% NH4HF2, 5% NH4Cl	1.0649	2.0 - 2.2	
10% Citric, 1.5% HF via 2.18% NH4HF2, 5% NH4Cl, 0.5% corr. inhib.	1.0649	2.0 - 2.2	
10% Citric, 1.5% HF via 2.18% NH4HF2+3.7% HCl(c), 5% NH4Cl, 0.5% corr. inhib.	1.0644	0.6 - 0.8	
10% HCl, 1.5% HF, 0.5% corr. inhib.	1.0518	0	
10% HCl, 1.5% HF, 2% chelating agent, 0.5% corr. inhib.	1.0557	0	

note 1: The density measurements were determined by weighing 100 ml in a polypropylene volumetric flask.

For reference, the density for deionized water was measured at 0.9980 gm/ml. Reference book values are 0.9978 @ 22°C(71.6°F) and 0.9975 @ 23°C(73.4°F).

note 2: The pH paper test strips used in these measurements are designated as Pehanon (Streifen) pH strips.

They are manufactured by Macherey-Nagel in Germany and are distributed by Gallard-Schlesinger here in the U.S.A.

TABLE 3 - ACID TREATMENT RESULTS

Well	Date	Lobes	Acid Type	Max. Pump Rate (BPM)	Pre-Acid Rates			Post-Acid Rates			Current Rates 11/3/97		
					bwpd	skin	Δ P (psi)	bwpd	skin	Δ P (psi)	bwpd	skin	Δ P (psi)
Producers													
A-2	7/1/96	70 & 80	Citric+HF	3	1,377	93	1,600	3,400	14	1,250	3133	12	1100
A-8	10/17/96	70 & 80	Citric+HF	3	116	100	2,000	1,590	24	895	1484	27	1650
A-3	5/13/97	30	Citric+HF	1.5	1,400	60	1,800	1,700	30	1,300	1421	54	1500
A-10	5/13/97	20, 70, 80	Citric+HF	9.5	2,400	60	1,600	5,660	18	1,500	4340	40	1700
A-9	5/14/97	10 & 20	Citric+HF	9.8	2,140	67	1,350	3,800	17	1,200	3100	22	1000
TOTAL					7,433			16,130			13,478		
Injectors													
A-14	8/1/96	10, 20, 30	Citric-ABF	3	1,500	211	2,700	7,800	42	1,400			
A-12	8/2/96	70 & 80	Citric-ABF	3	3,500	60	2,000	6,400	5	1,100			
A-12	10/29/97	70 & 80	Citric+HF	4.3	1,363	100	2,500	3,079	40	1,400	3275	50	1900
A-14	10/29/97	10, 20, 30	Citric+HF	9	2,277	100	2,600	8,977	10	1,200	9984	12	1400

* skin estimated using nodal analysis

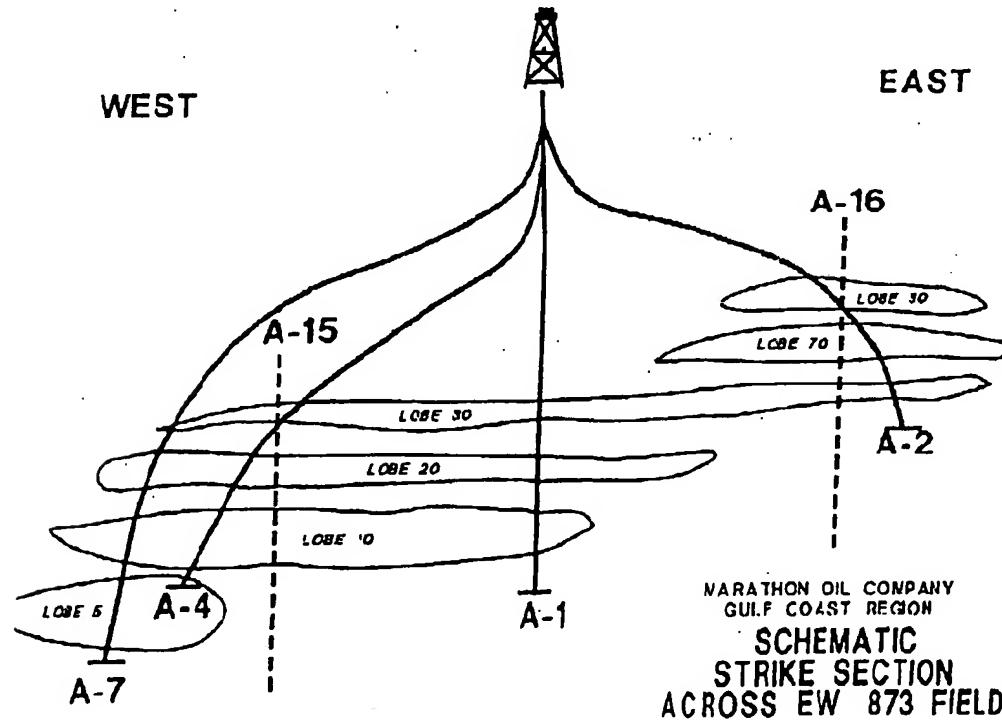


Fig.1 – Ewing Bank 873 stacked sand cross section.

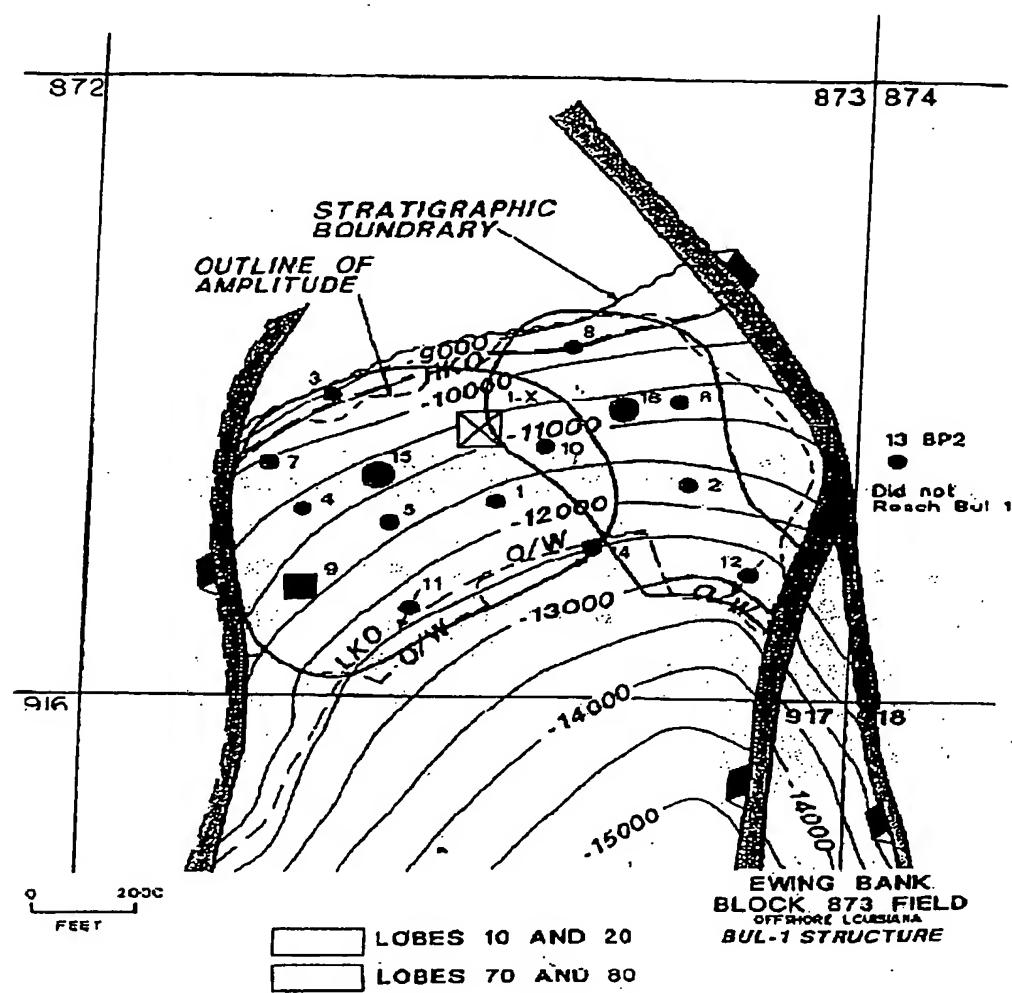


Fig.2 – Ewing Bank 873 BUL-1 structure map

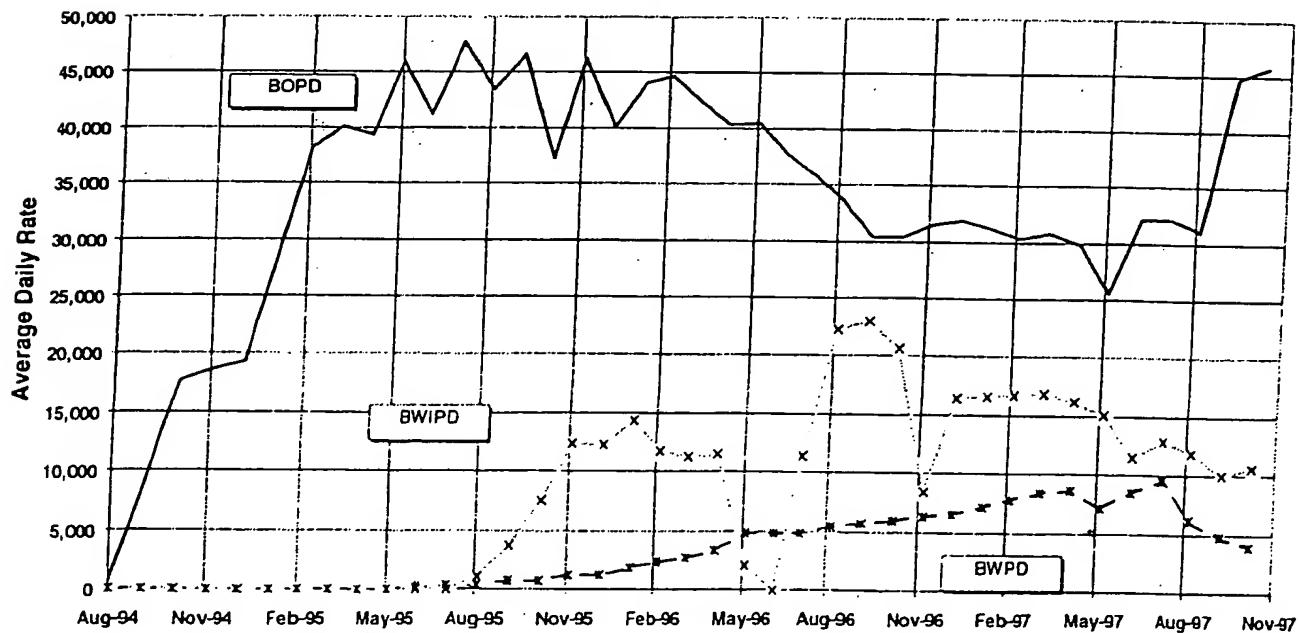


Fig.3 – Ewing Bank 873 production history.

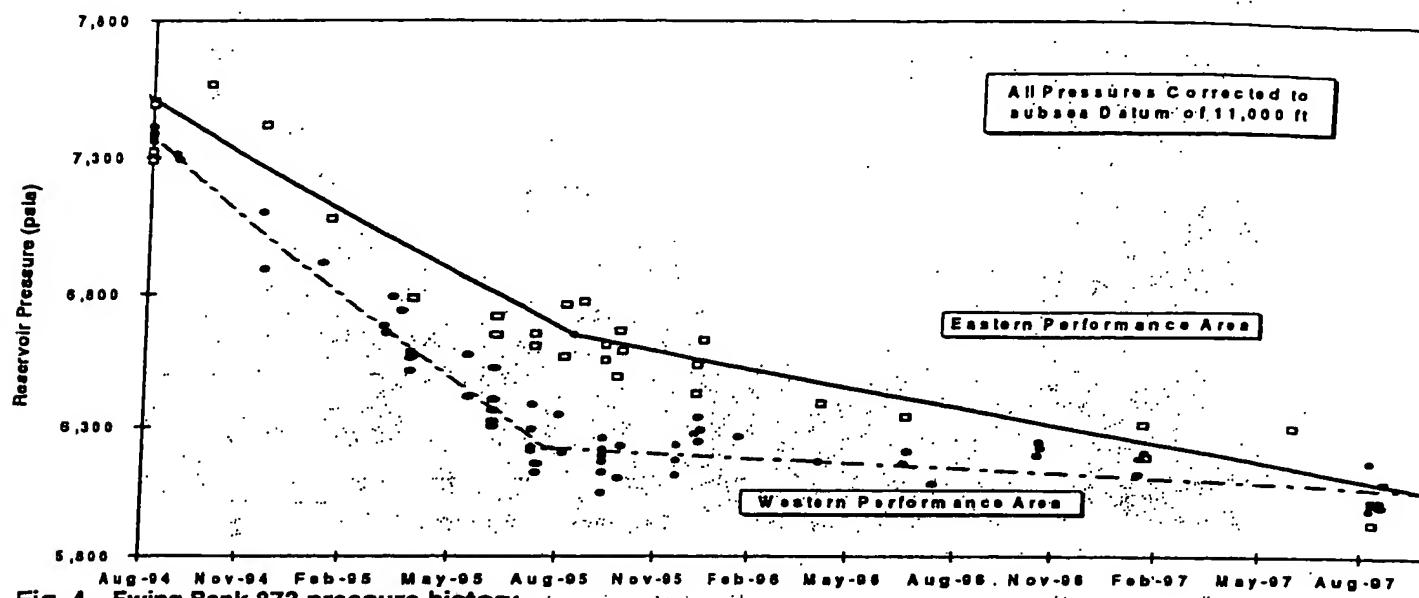


Fig. 4 - Ewing Bank 873 pressure history

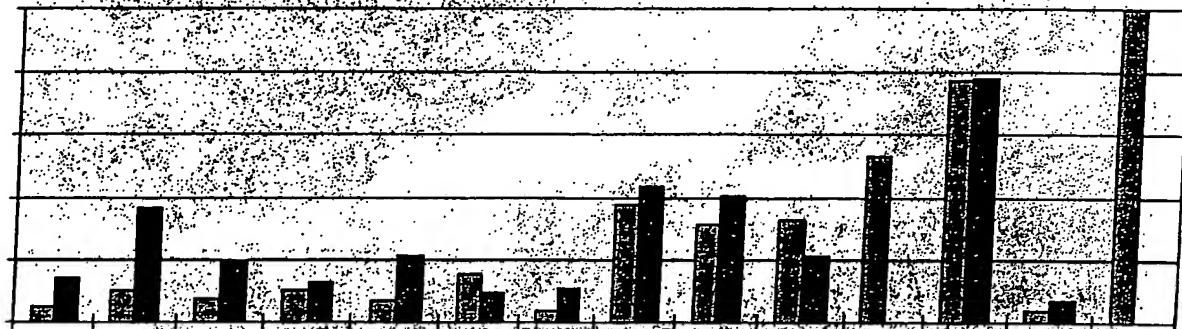


Fig. 5 - Comparison of initial completion skin and skins measured in January, 1996

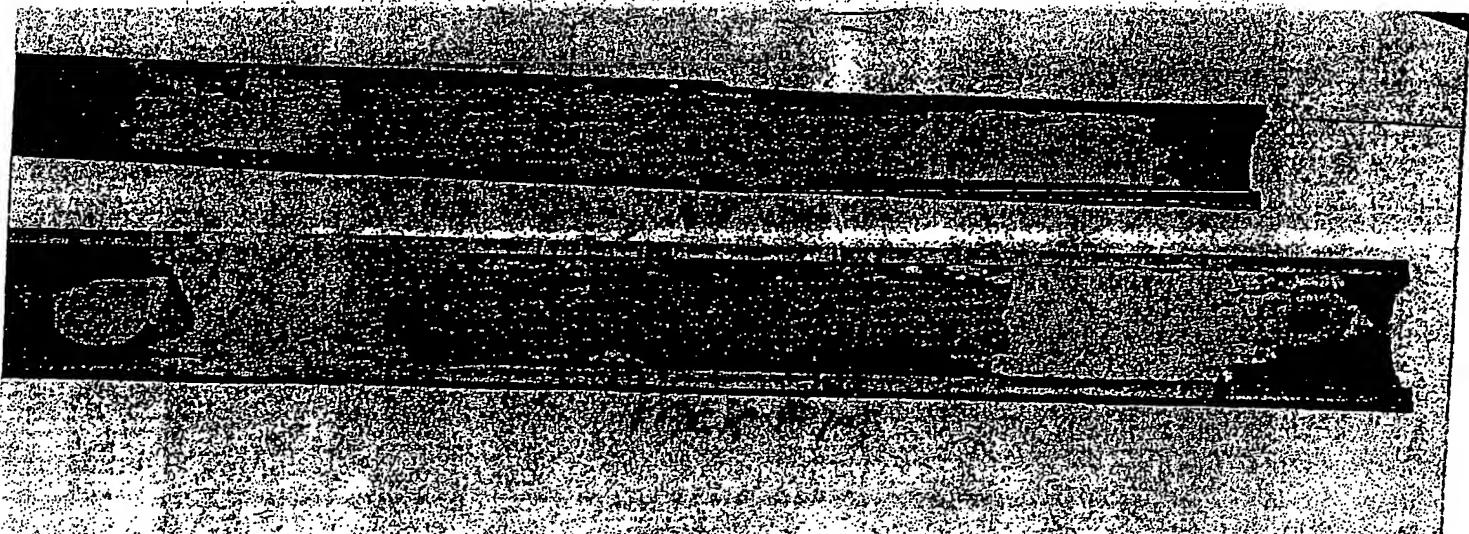


Fig. 6 - Example of sand pack, cut open after core flood.



Fig.7 -- SEM photograph of untouched zeolite platelets.

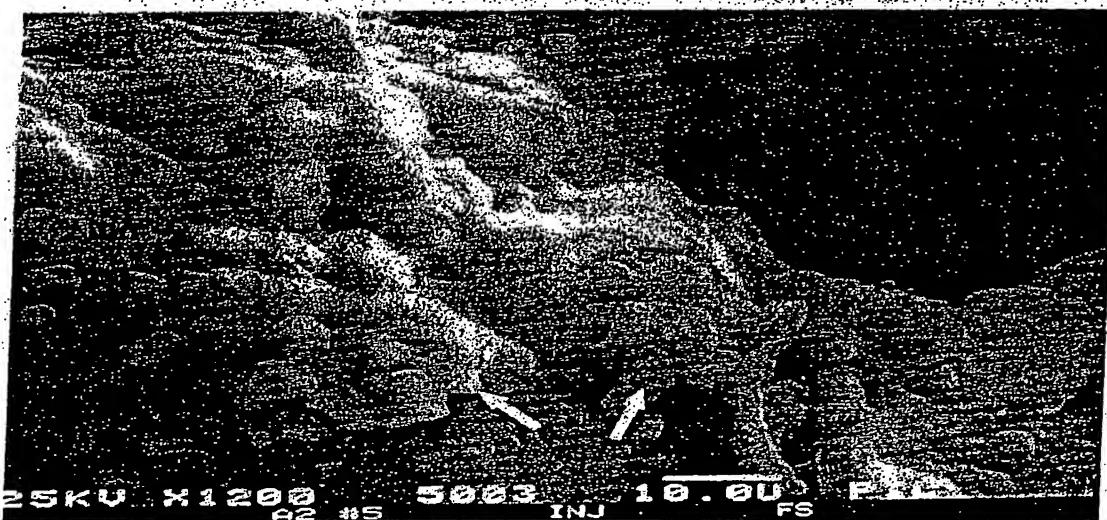


Fig.8 -- SEM photograph of incompletely dissolved zeolites and authigenic silica gel.



Fig.9 -- SEM photograph of Citric/HF flood showing good zeolite dissolution and no silica gel.

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